Impact of GHG limitation measures on the Russian electric power industry development

Fedor Veselov, Alla Makarova, Andrei Khorshev

Abstract - **The article presents results of an integrated analysis of technological capabilities and economic results of implementation of active policy on restriction of greenhouse gases (GHG) emission in the electric power industry of Russia, which is the biggest CO_2 emitter in the fuel and energy complex. To accomplish this, introducing a payment for CO_2 emission is considered as the main economic mechanism of a new ecological policy. The investigation incorporates a whole range of tasks on screening analysis of low- and non-carbon technologies on a basis of carbon avoided costs, system-wide optimization of their development scales and identification of generating capacity mix improvements until 2030 with a sequential estimation of an additional investment and price load on the economy in implementation of the ecology emphasized development strategy of the Russian electric power industry.**

Keywords – **GHG emissions, carbon avoided costs, low carbon technologies, investment and prices**

I. INTRODUCTION.

The problem of GHG emission decrease has a global and long-term dimension. The short duration of the Kyoto protocol and not very strong emission obligations adopted by the participating states can not considerably affect on the global emission trend. Many forecasts of global and national GHG emission scenarios shows that serious changes in trends (in terms of both rates and volumes) may be expected only near 2030 and in the following decades and should be supplemented by the technological shifts in production, processing and consumption of all energy resources, that will ensure qualitative improvements in efficiency of fossil fuel, electricity and heat utilization and a large-scale involvement of non-fossil energy resources.

Being the participant of Kyoto protocol, Russia has to formulate and implement a long-term (at least for the next 2-3 decades) economic and energy sector development strategy focused on the considerable limitation of GHG emission growth. Key parameters of such national strategy should be consistent with the sustainable development requirements and maximize the decrease of negative ecological consequences of the stable economic development without dramatic losses of competitiveness of Russian economy in global scale.

Our country became an active participant of the Kyoto process with a certain delay and still not formulated priorities and mechanisms of its own long-term GHG abatement policy. Although the existing gap between actual and targeted by Kyoto (1990 year) emissions still remains considerable, formulation and implementation of the active ecologically sound policy will create a good impetus to increase of energy efficiency in Russian economy and perform a technological modernization of the nation energy sector.

In Russia, as in the most other countries, electric power industry will potentially provide a main impact on GHG emission limitation. Being the largest domestic consumer of fossil fuels, the industry forms almost one third of total national GHG emissions now. At this electric power industry has the largest technological capabilities to change the structure and efficiency of different energy resources consumption through time-expanding spectrum of electric power production processes using fossil, nuclear fuel, hydropower and other renewable sources.

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II. ECONOMIC EVALUATION OF THE TECHNOLOGIES FOR GHG EMISSION REDUCTION IN THE RUSSIAN ELECTRIC POWER INDUSTRY.

In terms of carbon intensity (namely, specific CO_2 emission per a unit of generated electricity) all existing and advanced electric power generating technologies can be split into three groups:

- High-carbon technologies of coal-fired power plants with supercritical (SC) or ultra supercritical (USC) steam pressure units possessing the highest specific CO_2 emission; including power plants with coal gasification (IGCC) technologies;
- Low-carbon technologies of thermal power plants, which include modern combined cycle plants (CCGT) using gas with a less content of carbon as compared to coal, as well as combined heat-and-power plants (CHP) ensuring an efficient use of fuel in combined production of electric power and heat. This group also includes advanced technologies of coal- and gas-fired plants with CO_2 capture (up to 85-90%) and its subsequent compression, transportation and ultimate storage (CCS plants);
- Non-carbon technologies: nuclear power plants (NPP), hydropower plants (HPP), plants on renewable (wind, solar, geothermal) energy sources (RES plants) providing production of electric power with a zero CO_2 emission, as well as electric plants using wood or agricultural biomass which combustion emission is not accounted within the national cadastre of GHG emissions.

These groups of generating technologies differ fundamentally in a value of specific CO_2 emissions, coat and performance data (Table 1). A coal-fired USC power plant has been accepted as a "reference" plant to compare other low- and non-carbon technologies. A difference between specific emissions from the "reference" and any alternative low- and non-carbon technology makes up a so-called volume of "avoided emissions", which is also given in Table 1.

TABLE 1. COST AND PERFORMANCE DATA OF GENERATING TECHNOLOGIES AND CO_2 EMISSIONS

	Overnight capital costs [$/kW]	Efficiency [%]	Own consumption [%]	Specific CO_2 emissions [t CO_2/MWh]	Avoidable CO_2 emissions [t CO_2/MWh]
Coal-fired USC steam plant*)	2100 3550	47% 35%	5.0% 18.0%	0.73 0.10	- 0.63
CCGT plant*)	1250 2500	55% 47%	2.0% 7.0%	0.37 0.04	0.36 0.69
IGCC plant*)	2300 3100	52% 43%	6.0% 15.0%	0.41 0.05	0.23 0.68
Nuclear	2600	34%	6%	-	0.73
Wind (onshore/offshore)	1600/1850	-	1%	-	0.73
"Separate" heat-and-power supply scheme: Coal CPP (USC) + Boiler-house plant on gas	2100 (16700 $/GJ)	47% (93%)	5.0%	0.93	-
Combined cycle CHP	1380	75%**)	7.5%	0.46	0.47

*) upper levels – without CCS, lower levels – with CCS (90% capture)
**) for CHP– fuel utilization ratio

Screening analysis of various types of electric power plants is usually made by criterion of specific cost of a unit of generated electricity. Both in the Russian practice and in the practice of the International Energy Agency [1], an electricity generating cost (EGC) is used as such a criterion. Its value is determined by a relation of overall discounted cost to a discounted supply of electric power throughout the lifetime of generating technology. In its turn overall costs are determined as an sum of capital, fuel and other variable and fixed operation and maintenance expenses.

However, in evaluation of economic efficiency of power technologies to reduce greenhouse gas emission a somewhat different criterion is usually used, namely a carbon avoided cost [2, 3]. Its value is determined as a difference of EGC of the basic and alternative generating technologies referring to a respective specific value of "avoided emissions".

The cost estimating of carbon avoided cost for CHP producing electric and thermal power in one technological cycle (named as "combined heat-and-power supply scheme") is somewhat more complicated. A so-called "separate" heat-and-power supply scheme consisting of a combination of a coal condensing power plant (coal CPP) and gas-fired boiler-house plant is considered to be a "reference" one for CHP.

For each of these two heat-and-power supply schemes ("separate" and "combined") overall discounted costs are determined, provided that both power supply concepts are equalized by annual volume of heat delivery (heat output of a boiler-house plant equals a heat extraction load of CHP turbines), electric capacity (installed capacity of coal CPP and CHP are equal) and electricity output. As a rule, CHP annual capacity factor is lower as compared to the base-load coal CPP. Therefore, when equalizing the electricity output in the "combined" heat-and-power supply scheme with electricity output from the coal CPP, "additional" electricity is added to the lower annual CHP output, which ensures the same electricity output for two heat-and-energy supply schemes. It is assumed that this "additional" electric energy is also generated at coal CPP, and in estimation of overall discounted costs for the "combined" scheme it is accounted at a price equals coal CPP variable costs.

An annual volume of CO_2 emissions from CHP and alternative "separate" heat-and-energy supply scheme are calculated based on the total fuel consumption for electricity and heat production. For a "separate" scheme annual fuel consumption is determined through a coal CPP and boiler-house plant heat rates. In calculation of fuel consumption in a "combined" scheme CHP heat rates for electricity and heat are used, as well as fuel consumption for generating of "additional" electricity at coal CPP required for equalizing the outputs of two schemes.

Calculation of a carbon avoided cost for CHP is based on a relation of differences of non-specific, but absolute values of overall discounted costs and volumes of CO_2 emission for separate and combined heat-and energy supply schemes.

Fig. 1 depicts actualized estimates of ranges of carbon avoided costs for various types of generating technologies at a level of 2020, taking into account an uncertainty of capital costs and domestic fuel prices within this period. All economic results provided in the paper are given in constant US dollars of 2007.

Analysis of economic ranking shows that three basic generation technologies (nuclear power plant, as well as CCGT and gas-fired CHP) within a wide range of uncertainty have the least carbon avoided costs (up to 30-40 $ per ton of CO_2, that is approximately consistent with a cost of emissions in EU anticipated by 2020 [4]) and they are eventually equally effective alternatives for CO_2 emission reductions in the Russian electric power industry. Another comparatively inexpensive alternative is a development of thermal power plants using biomass. For them a wide range of carbon avoided costs is primarily determined by a high uncertainty of cost of local biomass resources.

The other low- and non-carbon technologies appear to be less competitive with NPP, CCGT and CHP due to significantly higher carbon avoided costs. For wind power plants it is caused by the low capacity factors. For thermal power plants with CCS critical factors are a significant growth of capital costs (by 60-80% for coal plants and by 2 times for CCGT) and own electricity consumption needs to recover sorbents (by 13-15 percentage points for coal plants with CCS and by 5 percentage points for CCGT) [2]. Besides, the carbon avoided cost for CCS plants shall be added with expenditures for CO_2 transportation and final storage in the geologic beds or worked-out oil-and-gas minefields, which will be noticeably higher than the European cost with regard to the length of the territory of Russia and a distance of potential disposal sites.

High costs of "avoidable emissions" for power plants on renewable energy sources and "clean" coal plants with CCS are a serious obstacle for their growth, specifically under conditions of a competitive market. Even with regard to an expected cheapening of these technologies as they are widely implemented, their competitiveness can be ensured only through special measures of economic encouragement. The most obvious measures (actively used in many member countries of the Kyoto protocol) are evident or implicit subsidies of the owners of "green" electric power plants at the expense of budget or at the expense of consumers collected as an additional charge in a final electricity price. However a more integrated approach by its effect is an introduction of payment for CO_2 emission, acting as a unique tax penalty on usage of fossil fuel.

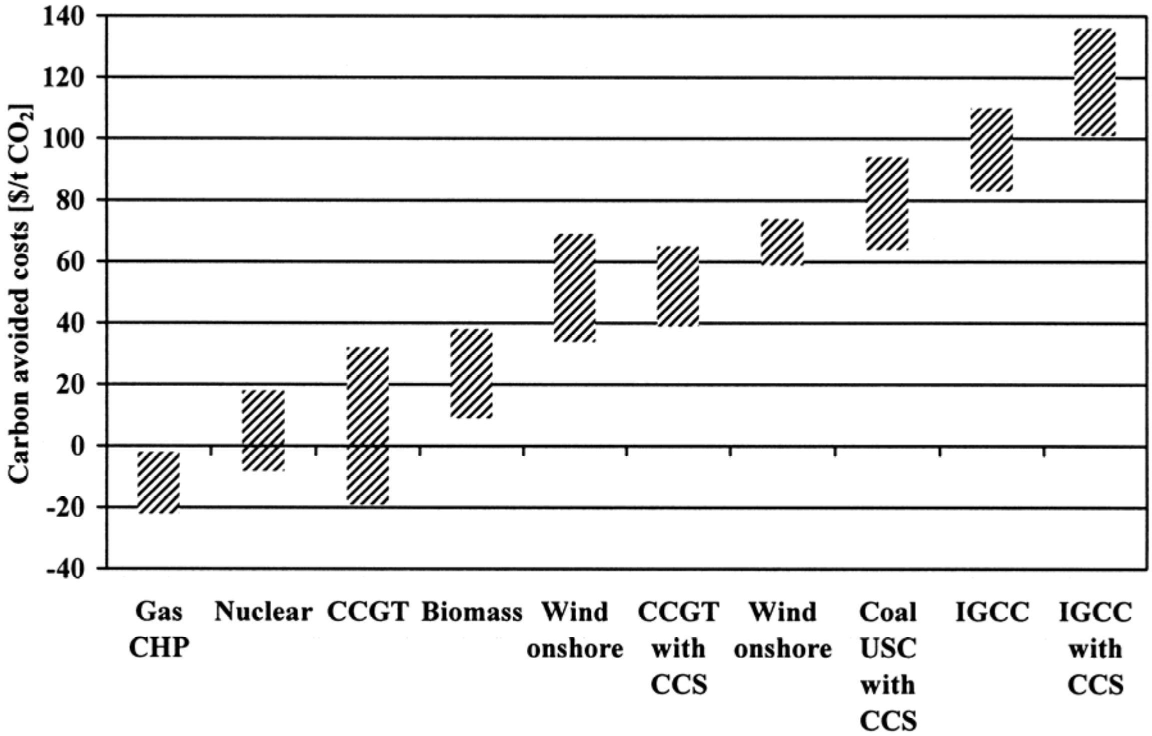

Fig. 1 - Range of carbon avoided costs for low and non-carbon technologies (at 10% discount)

III. CHANGES IN THE ELECTRIC POWER INDUSTRY STRUSTURE UNDER DIFFERENT SCENARIOS OF GHG EMISSION LIMITATION AND PAYMENTS

A system-wide evaluation of changes in the structure of generating capacities, production of electric power and centralized heat, with impact of CO_2 emissions payment, was performed using EPOS – dynamic LP model for joint optimization of electric power industry and fuel supply industries development [5]. The EPOS model is developed by ERI and solves linear programming task with a planning horizon of 30-40 years. This makes it possible to take into account an «end-effect» and obtain an adequate economic ground for strategic solutions on developing generating and network capacities adopted for the nearest 10-20 years (Fig. 2). Comparing with the previous versions, an extended set of electricity and centralized heat production technologies with limits on rates and volumes of their development is considered in EPOS-CARBON. Development of nuclear plants is limited by the provided of inexpensive uranium fuel resources and the rates of new nuclear units' construction and commissioning. Development of wind and other RES generation are mainly limited by the efficient potential of renewable resources at the area of Unified Power System. Limits on the "clean" coal-fired CCS generation growth are defined by the schedule of development and industrial-scale commercialization of carbon capture and sequestration technologies.

EPOS-CARBON contains a more detailed description of limits for capacity utilization modes of different generating technologies (incl. RES plants) in balances for electricity, heat and installed capacity supply and demand. Besides this, additional limits for allowed CO_2 emission and available resources for the electric power industry are also added into the model. These additions are narrowing the field for optimization of structural and technological changes in the industry under the following dilemma – “emissions vs. investments”.

A list of variables and balance constraints of EPOS ensures a system-wide review and economic ranking of a set of investment alternatives on technical upgrading of the existing electric power plants and new (green-field or brown-field) construction of new electric power plants of a different type (HPP, NPP, CPP and CHP on gas and coal, RES plants), boiler-houses and new intersystem power transmission lines with regard to: (1) uncertainty of their coat and performance data, (2) limited volumes of investment resources, (3) limited volumes of GHG emission and (4) ensuring balance conditions for demands in generating capacity, electricity, centralized heat and fuel supply to domestic and export markets across the main energy consuming regions of Russia.

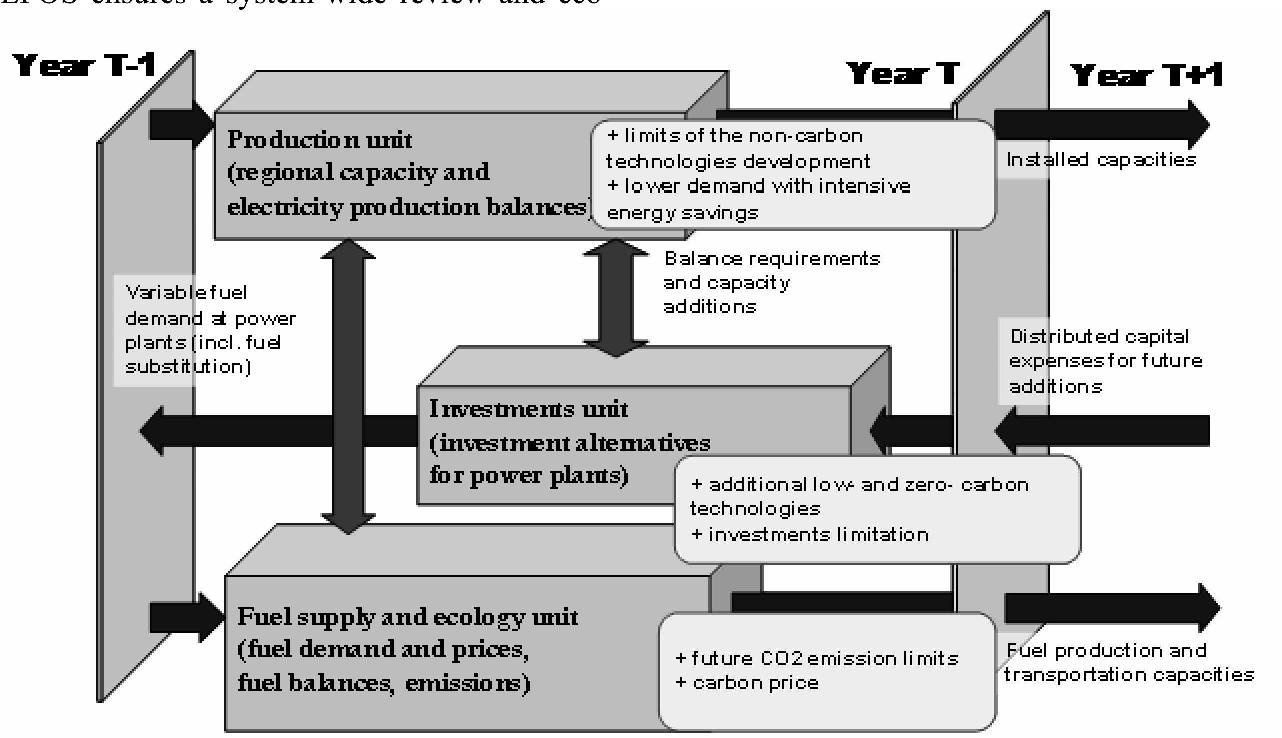

Fig. 2 – Structure of the static (one year or stage) unit of the dynamic LP optimization model for the electric power and fuel supply industries development under CO_2 limitation requirements (EPOS-CARBON)

The scenario corresponding to parameters of innovation development of national economy and energy sector provided in the Energy Strategy of Russia for a period until 2030 was adopted as a “BASE” case for a following multi-case optimization. The implementation of this scenario provides for serious changes in the production structure of the electric power industry, although they are not accompanied by introducing a payment for CO_2 emissions or other dedicated economic measures for reducing greenhouse gas emission.

The main development trend of electric power industry in the “BASE” case for a period until 2030 will be a growth of nuclear generation share from 16% in 2005 to 28% (Table 2). With a common decrease of a share of thermal generation in electricity production structure the share of coal CPP will increase from 10% to 16%. Dynamics of CHP capacities will be determined by extremely moderate growth of centralized heat demand. Even provided that CHP ensure the main growth of heat demand, their share in the electricity production will be reduced from 37% to 23%.

Changes in projected electricity production structure caused by introduction of payment for CO_2 emissions were investigated within a wide range of its values. In all cases the CO_2 payment are introduced after 2015, and by 2020 a "cost" of a unit of greenhouse gas emissions will be 10-50 \$/t CO_2, and in 2030 it will be 25-100 \$/t CO_2 (Table 2).

As shown by the optimization results, additional carbon-related payments will create serious economical incentives for structural shifts in the electric power industry to 2030 due to reduction of a fraction of condensing thermal power plants. Primarily, it concerns a reduction of a fraction of coal CPP (from 16 to 8-12%), the efficiency of which replacement becomes economically obvious. At the same time, as shown in Table 2, a fraction of gas CPP is also reduced from 21 to 15-17%. The efficiency of gas CPP replacing is determined by the fact that the carbon avoided costs for competitive gas CHP and NPP technologies are comparable or lower (Figure 1). The introduction of payment for CO_2 emission provides an additional impetus for developing combined power-and-heat generation in Russia. A share of CHP in a total production of electric power increases from 23% in a "BASE" Case to 27-31%. At this, CHP share is also growing in a centralized heat supply structure pushing out an application of a «separate» heat-and-power supply scheme and reducing a share of boiler-house plants in heat production structure.

TABLE 2 – PARAMETERS OF ELECTRIC POWER INDUSTRY DEVELOPMENT IN 2030 AT DIFFERENT LEVELS OF PAYMENT FOR CO_2 EMISSIONS

		2005	2030				
			BASE	1	2	3	4
Payment for CO_2 emissions, \$/t CO_2		-	-	25	50	75	100
Electricity production *) [TWh]	Totally	944	1843	1843	1843	1843	1843
	Hydro power and RES plants	175	202	226	267	269	272
	Nuclear power plant	149	523	531	569	569	569
	Thermal power plants, incl.:	620	1118	1086	1007	1005	1001
	- combined heat-and-power plant (CHP), incl.:	352	436	493	523	552	569
	on gas (and fuel oil)	208	278	341	377	416	436
	on coal (and other solids)	144	158	151	146	137	132
	- condensation power plant (CPP), incl.:	268	682	594	484	452	433
	on gas (and fuel oil)	175	380	381	313	291	272
	on coal (and other solids)	93	302	212	171	162	161
Heat from CHP and boiler-house plants [Pcal]	Totally	1262	1449	1449	1449	1449	1449
	CHP	597	739	785	814	831	839
	Boiler-house plants	665	710	664	635	618	610

*) centralized electric power supply zone

A fraction of non-fossil sources (hydro, nuclear and renewables) increases something like this (from 39% to 41-46%), specifically when payment for emissions exceeds 50 \$ /ton of CO_2. A relatively slight additional increase of nuclear generation is caused by the fact that in the "BASE" Case itself an intensive development of NPP is envisaged.

Forecasted structural and technological changes in electric power industry such as increase of the share of non-fossil generation sources and efficiency improvements in thermal generation resulted to the decrease of heat rates due to the development modern GT, CCGT and USC coal technologies will suppress the growth of fossil fuel consumption for power plants. In a "BASE" case fuel consumption will increase at 50% by 2030 and will reach 400 Mtce. At this the share of gas in the

"fuel mix" will decrease from 69% to 61% (Table 3).
A suppression of growth of fuel consumption slows down greenhouse gas emission, but at the same moment, a growing fraction of coal will contribute to its additional increase. As a result of multidirectional action of these factors annual CO_2 emissions from electric power plants will increase by 60% by 2030 as compared to 2005.

TABLE 3 – FOSSIL FUEL CONSUMPTION AND EMISSIONS IN ELECTRIC POWER INDUSTRY IN 2030 AT DIFFERENT LEVELS OF PAYMENT FOR CO_2 EMISSIONS

		2005	2030				
			BASE	1	2	3	4
Payment for CO_2 emissions, \$/t CO_2		-	-	25	50	75	100
Fuel consumption of power plants *) [Mtce]	Totally	275	407	396	375	370	365
	Gas	189	249	265	260	263	263
	Coal	70	137	109	93	84	79
	Fuel oil and others	16	21	22	22	23	23
CO_2 emission [Mt]	Totally	535	817	765	711	691	677
	Gas	308	405	431	423	428	428
	Coal	193	379	302	257	233	219
	Fuel oil and others	34	32	33	31	30	29

*) centralized electric power supply zone

A total fuel consumption at all levels of payment for CO_2 emissions will be lower than in the "BASE" Case, with a noticeable reduction of a coal and successive increase of gas share. As shown in Table 3, the main part of fuel consumption decrease (to 10% from comparing to the "BASE" Case) is obtained at payment rate up to 50 \$/ton and it is resulted from the additional development of non-fossil generation. Further increase of CO_2 payments will not decrease fuel consumption so much. At all emission payment levels an absolute volume of gas consumption in the electric power industry will be higher than in the "BASE" Case and at a maximum level of payment in 2030 a structure of "fuel mix" in the electric power industry eventually goes back to up to date.
Therefore, the introduction of additional ecological constraints noticeably complicates the task of forming the rational scenarios of electric power industry development corresponding to requirements of the Energy strategy for diversification of structure of consuming primary energy resources and reducing gas share in electric power industry.A total reduction of CO_2 emission in 2030 can amount up to 140 million tons, i.e. up to 20% from emission volumes in the "BASE" Case (Table 3). A minimum payment for emissions (25 \$/t CO_2) will ensure 37% of this volume (more than 50 million tons), the same amount will be provided by its increase up to 50 \$/t CO_2. However a higher payment levels gives a less and less effect.
It is important to note that an emission reduction is relative, as shown at Fig. 3, an annual emission reduces as compared to the "BASE" Case, but its absolute volumes increase until 2030 at any payment level (only in "30-100" Case at a maximum payment of 100 \$ /t CO2 their stabilization is almost reached).

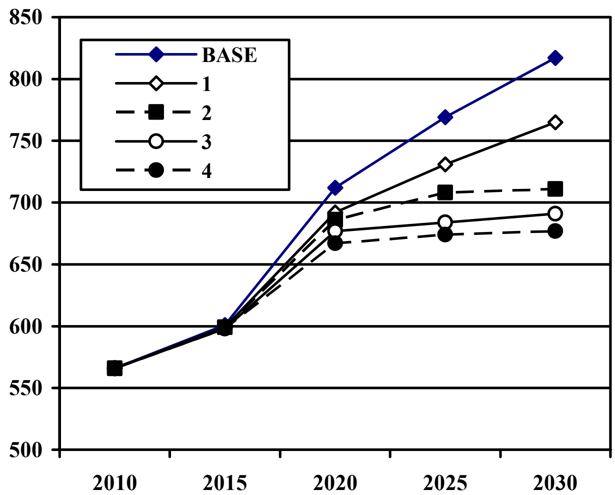

Fig. 3 – Growth of CO_2 emissions in electric power industry at different levels of CO_2 payments, Mt CO_2.

A sequential decrease of coal share in a "fuel mix" of electric power industry will cause a noticeable reduction of its contribution into CO_2 emission from the electric power plants (Table 3). If in the "BASE" Case the coal burning gives more than 45% of emissions in the industry in 2030, in alternative options this fraction decreases up to 32-39%. In this case, the main emission volume as at the present time will be determined by gas burning.

At relatively low differences in gas consumption across the cases a volume of CO_2 emission caused by gas burning at the electric power plants in 2030 will also be changed within a rather narrow range (420-430 Mt). However, in percentage ratio, if in the "BASE" Case in 2030 gas gives nearly a half of CO2 emissions in the electric power industry, then when going back to a report structure of fuel consumption in the Cases with payment for CO2 emissions gas contribution to emission will also go back to a report level and will amount to 56-63 %.

IV. ECONOMIC CONSEQUENCES OF GHG EMISSION REDUCTION SCENARIOS IMPLEMENTATION IN ELECTRIC POWER INDUSTRY.

The shifts identified in the production structure and fuel balance of the electric power industry exercise a significant influence on the parameters of the investment and price policy. An integrated financial and economic evaluation of case of electric power industry development in the range of CO_2 emission payments is made using ELFIN model which determines dynamics of cash flows from the operational, investment and financial activities, forecasts an industry financial plan, selects a rational structure of investment financing, and predicts necessary levels of electricity (and heat) prices providing the feasibility of proposed investment and production program.

Changes in the structure of generating capacities caused by payment for CO_2 emissions will result to additional investments to more expensive projects of non-fuel plants and CHP having lower or zero CO_2 emissions. If in the "BASE" Case total investments to electric power plants within a period until 2030 are estimated at $ 363 billion, at a minimum level of emission payment (25 $/t) the incremental investments will be about $ 9 billion, and at a maximum level (100 $/t) it will be $ 86 billion (Table 4).

As the payment for CO_2 increases, additional emission reduction will require even higher investment costs, which are illustrated by a curve of "capital intensity" of an additional unit of emission reduction (Fig. 4). A more simple approximation by a linear trend (with a quite good coincidence R^2~0.96) shows that "at the average" to reduce CO_2 emissions relative to the "BASE" Case by 10 million tons will require more than $ 7 billion.

TABLE 4 – CAPITAL COSTS AND REVENUE REQUIREMENT STRUCTURE OF ELECTRIC POWER INDUSTRY IN 2030 AT VARIOUS LEVELS OF PAYMENT FOR CO_2 EMISSIONS

		Cases				
		BASE	1	2	3	4
Capital costs, $ bln	Accumulated 2010-2030	362.6	371.8	416.7	430.4	448.7
	Additional to the "BASE" Case	-	9.2	54.1	67.8	86.1
Revenue requirement in 2030, $ bln	Total revenue requirement	152.9	175.9	201.9	221.4	241.9
	Fuel costs	62.0	64.0	61.9	61.9	61.5
	Payment for CO_2 emissions	0.0	19.1	35.5	51.8	67.7
	Other costs	50.0	49.1	49.6	50.3	51.4
	Investment, taxes and profit	41.0	43.7	54.8	57.3	61.3

The impact of payment for CO_2 emissions seriously changes the structure of revenue requirements of the thermal power plants and the entire industry. As shown in Table 4, by 2030 annual payments of electric power plants for CO_2 emission will appear to be comparable to the cumulative additional investments for emission reduction.

The volumes of payment for CO_2 emissions by 2030 also appear to be comparable with total fuel costs. Affecting as an additional tax for fossil-fuel power plants, it may additionally increase fuel costs up to 1.5-2 times.

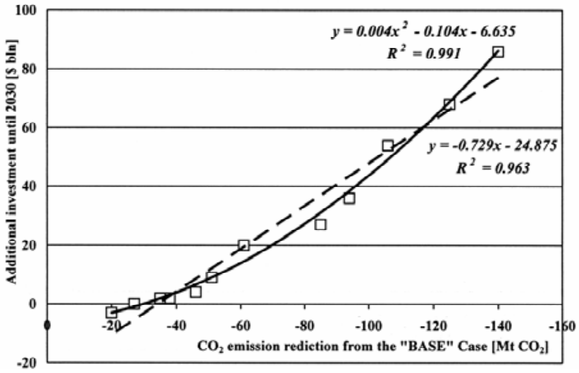

Fig. 4 – Additional investment requirements for reducing CO_2 emissions in electric power industry (relative to the "BASE" Case)

Integrated sensitivity analysis of electricity prices to the level of CO_2 payments shows that on average the emission reduction by 10 million tons of CO_2 will result in a rise in electricity price by 0.4-0.5 cent/kWh (Fig. 5).

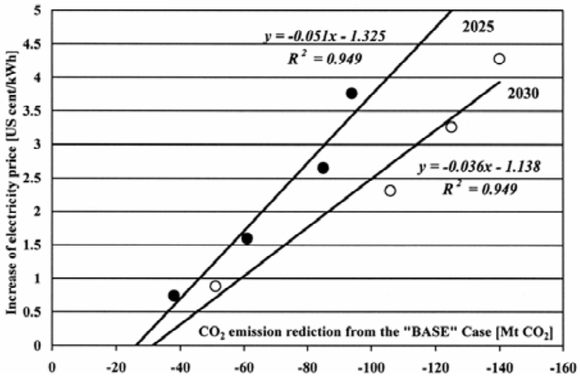

Fig. 5 – Sensitivity of electricity prices to reduction of CO_2 emissions in electric power industry (relative to the "BASE" Case)

Therefore, the study showed a high sensitivity of production, investment and price parameters of electric power industry to measures of economic stimulation of CO_2 emission limitation through introducing a payment for emissions. Possible shifts in the production structure, fuel consumption mix, investment and price impacts of the industry, certainly, have an inter-sector and macroeconomic scale and require an integrated evaluation of consequences for the national economy as a whole.

V. CONCLUSION.

The performed analysis of capabilities and consequences of GHG emissions limitation measures in the electric power industry provides definite grounds to generate a reasonable ecological policy in the industry preserving from the serious macroeconomic damages. The basic strategic trends in the industry are an increase of a fraction of nuclear power industry with a concurrent increase of efficiency of thermal power plants. In spite of the doubling of electricity production volumes, this will ensure to increase the fuel consumption only by 50% and limit a growth of annual CO_2 emission.

The introduction of payment for CO_2 emissions, as shown by model optimization results, can really become a serious economic incentive for deeper structural changes to the advantage of low- and non-carbon technologies, development of non-fuel sources and most efficient CHP fossil fuel technologies. The structural and technological shifts will ensure a reduction of an overall fuel consumption, but will contribute to preservation of a high fraction of gas in the "fuel mix' of the industry and increase of absolute volumes of its consumption. This will make it possible to significantly (up to 140 million tons or up to 20%) reduce emissions against the "BASE" Case, although in absolute terms they will keep growing or in the best case they will be stabilized.

The financial-economic evaluation of electric power industry development under different levels of CO_2 payments showed a need for a significant correction of investment and price policy parameters. Thus, a "capital intensity" of an additional unit of emission reduction «on average» will be more than $ 7 bln per 10 million tons of CO_2. Additional ecological payments of thermal power plants will greatly increase a cost of electricity produced at thermal power plants, reaching 50-100% of fuel costs and seriously deteriorating competitiveness of thermal (esp. coal) generation. A growth of investment and operational expenses will be inevitably reflected both on the electricity and heat prices' growth. The obtained assessments demonstrate that a reduction of CO_2 emission in the electric power industry per each 10 million tons will lead to a growth of price of electric energy on average by 0.4-0.5 cent/kWh. These results allows to make a more general macroeconomic analysis and justification of an acceptable level of GHG emission obligations of Russia, based on the calculations of changes in growth rates and structural changes in the national energy sector and slowdown the Russian economy growth.

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